ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills 26R Storage Project

Version History

File Name	Version	Date	Description of Change
Attachment A - Narrative	1	01/11/21	Original version was submitted as Attachment A - Narrative
Attachment A Site Characterization	2	05/31/22	Site Characterization Evaluation
Attachment A Site Characterization	3	12/20/22	Site Characterization Evaluation

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate four CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) 26R reservoir located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the 26R Monterey Formation reservoir up to 1.46 million tonnes annually for 26 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 tonnes per annum) with additional potential CO2 from the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of four injectors, surface facilities, and monitoring wells. This supporting documentation applies to the four injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

Class VI - Wells used for Geologic Sequestration of CO_2

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

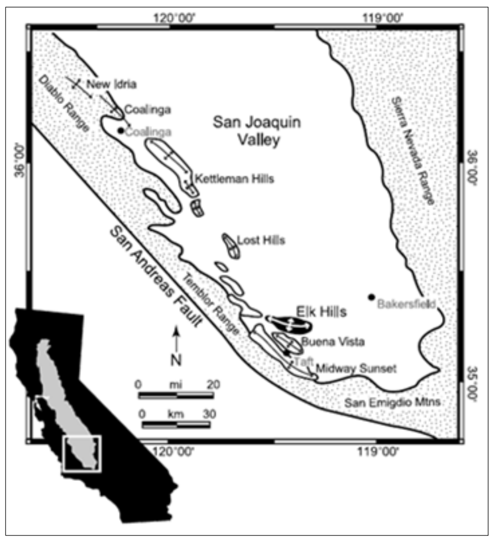
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation 26R sequestration reservoir was discovered in the 1940's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

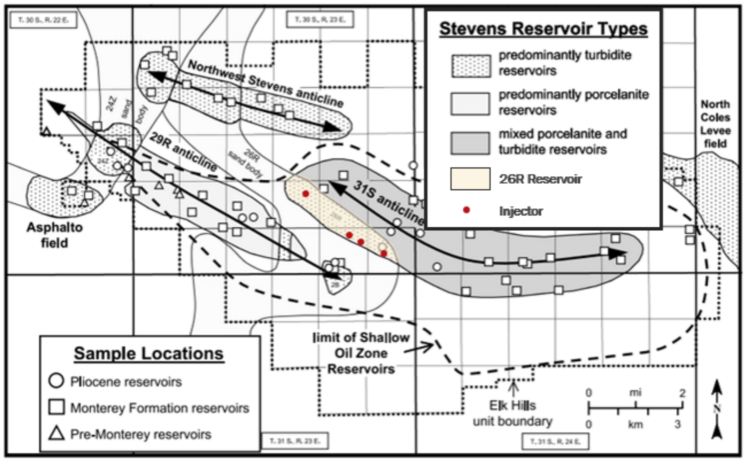
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



The EHOF has three anticlines Northwest Stevens, 31S and 29R that (Figure 2) are separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).`

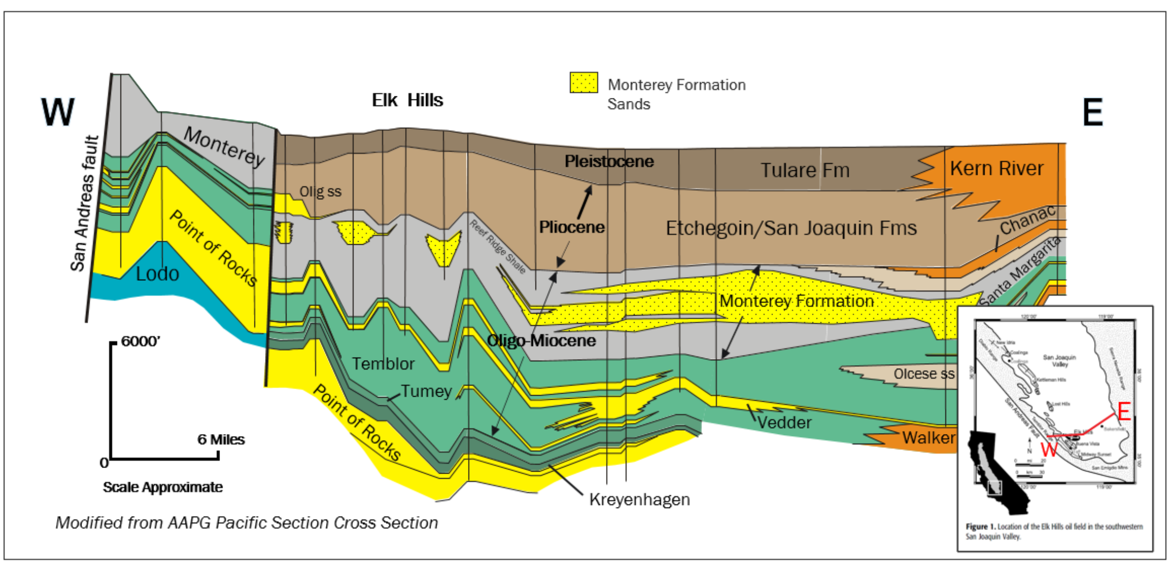
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation 26R CO2 sequestration reservoir is located in the 31S anticline (Zumberge, 2005). Sample locations for oil geochemistry are shown.



Geological Sequence

Figure 3 shows the stratigraphy of the EHOF. The Miocene aged Monterey Formation 26R reservoir at the 31S anticline is approximately 6,000 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by over 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



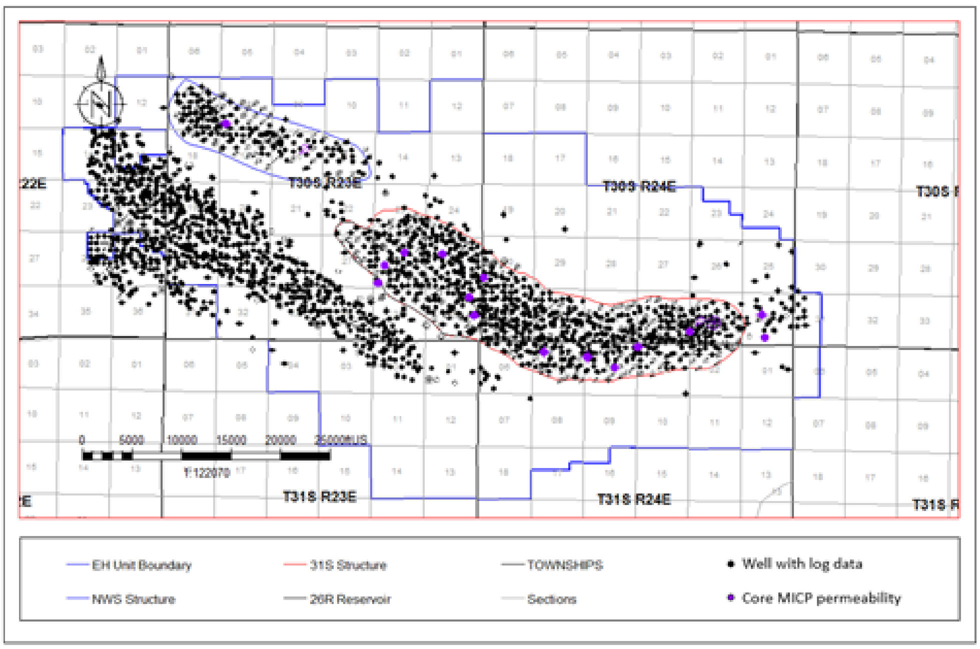
Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for the Monterey Formation 26R reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 4), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

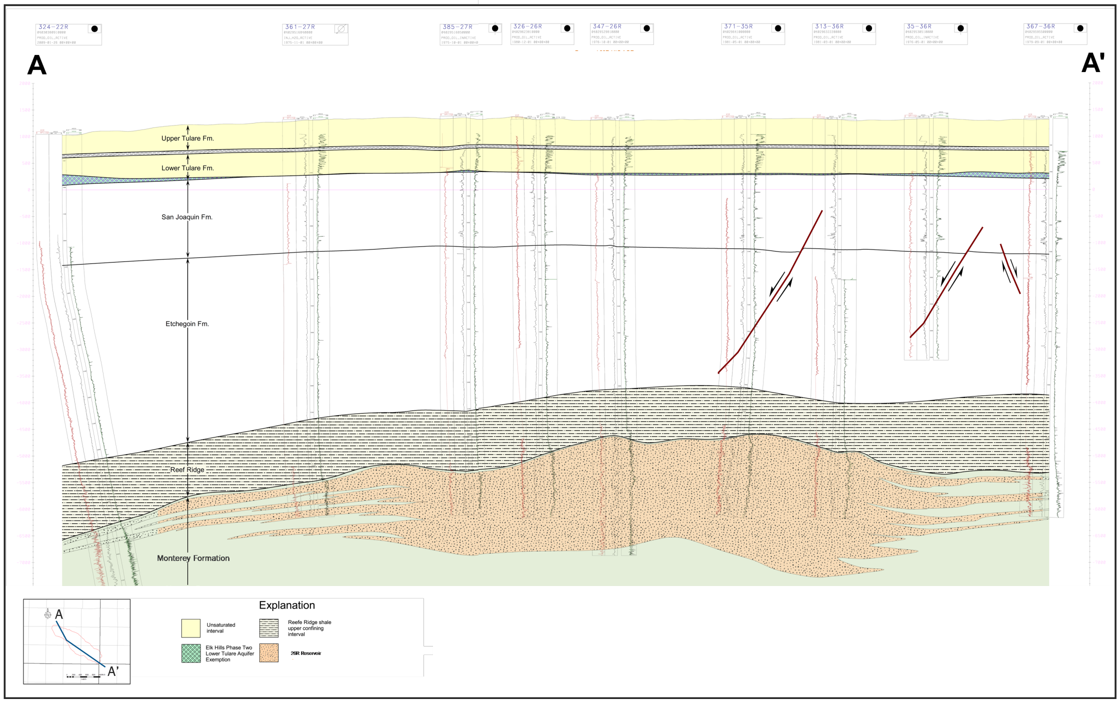
Figure 4: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs that define structure and lithology of the storage reservoir and Reef Ridge confining layer. Wells with MICP core from the Monterey Formation are shown in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation, Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 5 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 5: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the 31S anticline.



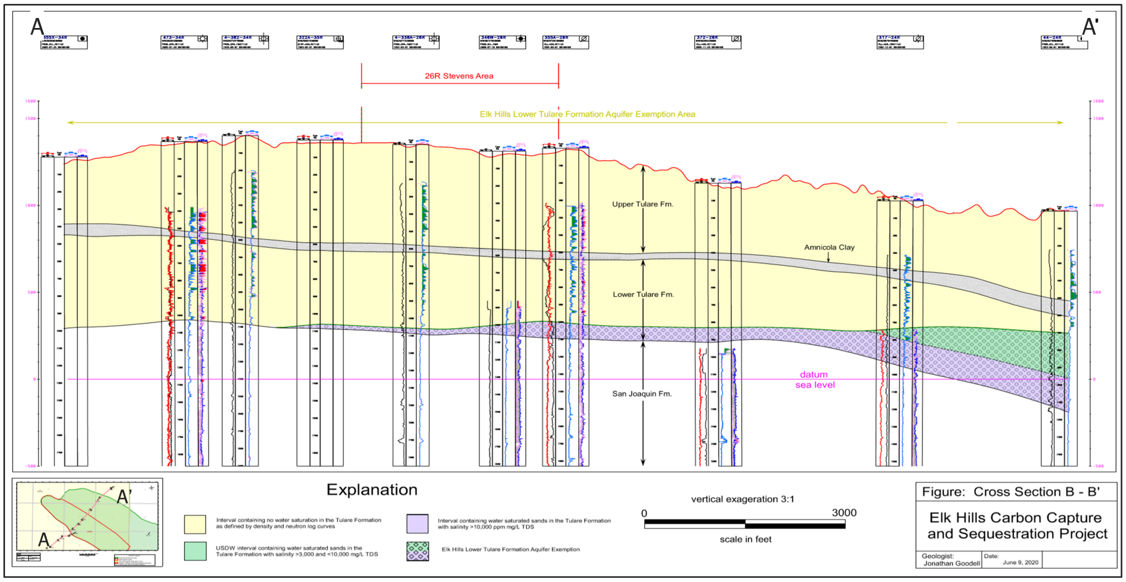
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 6), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare is an unsaturated air sand above the Monterey Formation 26R reservoir. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 6: The Tulare Formation consists of the Upper Tulare and Lower Tulare separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer and the Upper Tulare is an unsaturated air sand.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds (Maher et al., 1975). The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

The Etchegoin Formation will dissipate CO_2 and CTV will drill and equip a monitoring well to assess formation pressure and water quality changes during the project.

Reef Ridge Shale

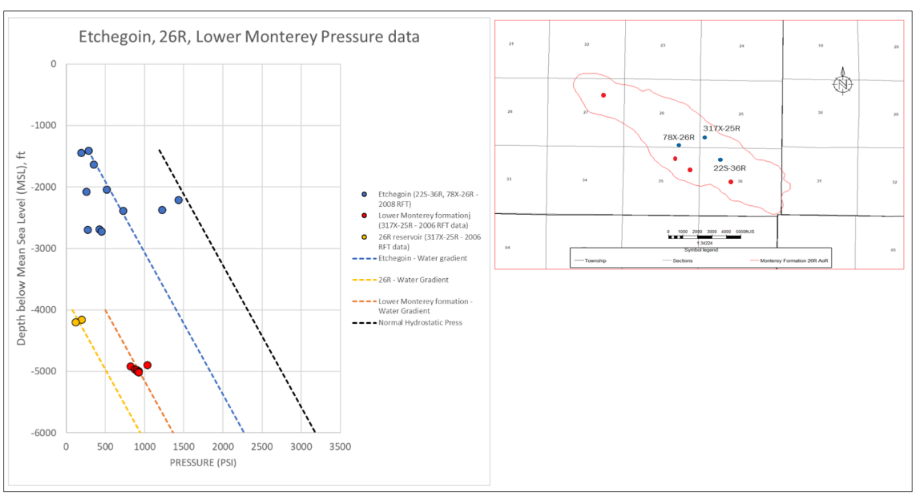
Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 5,000 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the 26R Monterey Formation sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

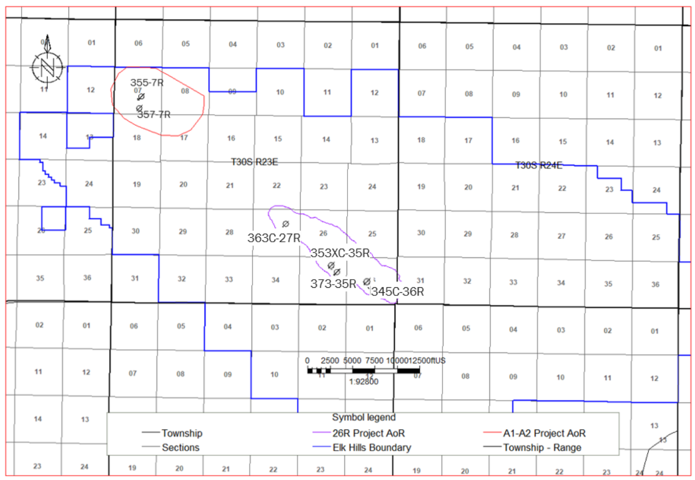
The 26R Monterey Formation sequestration reservoir is approximately 6,000 feet deep and produces from turbidite sands with an average permeability and porosity of 45 mD and of 25% respectively. Turbidite reservoir sands are bound above and below by siliceous shale that have a permeability of less than 0.01 mD. Pressure data shows isolation between the storage reservoir and the Etchegoin Formation above and Lower Monterey Formation below.

Figure 9 : Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



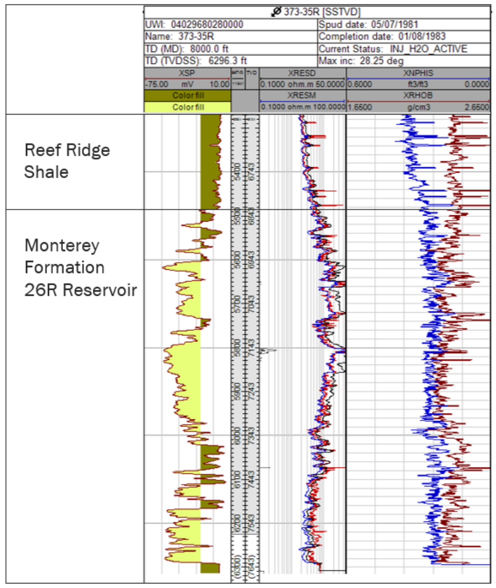
The 26R Monterey Formation sands were deposited as a turbidite channel influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. The turbidite sands were largely aggregational with minimal erosive deposition.

Figure 7: AoR and injection well location map for the Elk Hills 26R project and Elk Hills A1-A2 project. Well location shown is defined by the well path intersection with the Monterey Formation. The distance between the four injectors is 6,800 feet (363C-27R to 353XC-35R), 1,000 feet (353XC-35R to 373-35R) and 3,400 feet (373-35R to 345C-36R).



The reservoir is continuous across the AoR and the sands pinch-out up-dip and on the channel edges (Figure 5). As such, the 26R Monterey Formation sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

Figure 8: 373-35R injector showing the Monterey Formation 26R reservoir.



Summary:

The Monterey Formation 26R project will be developed with four injectors (Figure 7), three wells to be drilled prior to the initiation of injection and the existing 373-35R well (Figure 8).

The storage reservoir depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement.

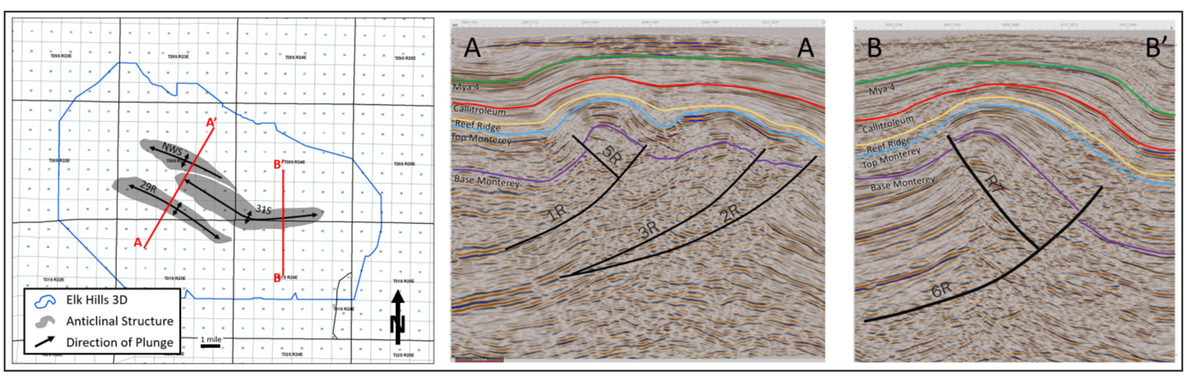
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the 31S anticline are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale in the Monterey Formation 26R reservoir. CTV reviewed the seismic in the AoR and assessed all the major reflectors. There were no reflectors showing offset of the Monterey Formation nor Reef Ridge in the AoR that would indicate faulting.

Figure 9: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

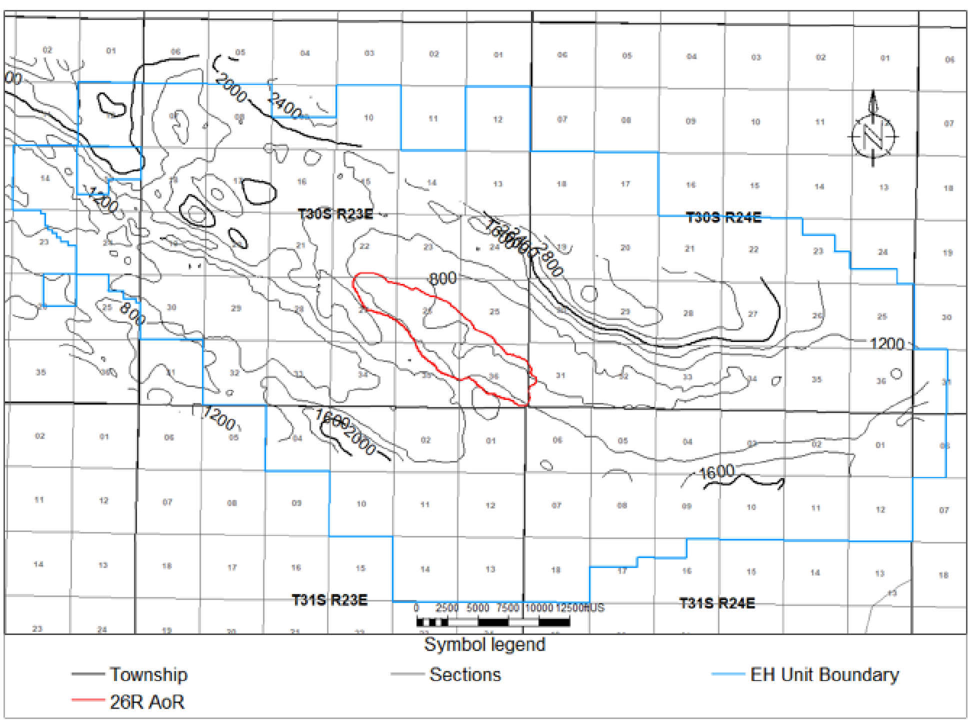
Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the 26R Monterey Formation sands:

1. There are no reflectors on the 3D seismic that either indicate off-set of the Monterey Formation within the AoR or faults that extend into the confining Reef Ridge Shale (refer to Figure 9).
2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,000 feet (Figure 10) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 10: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

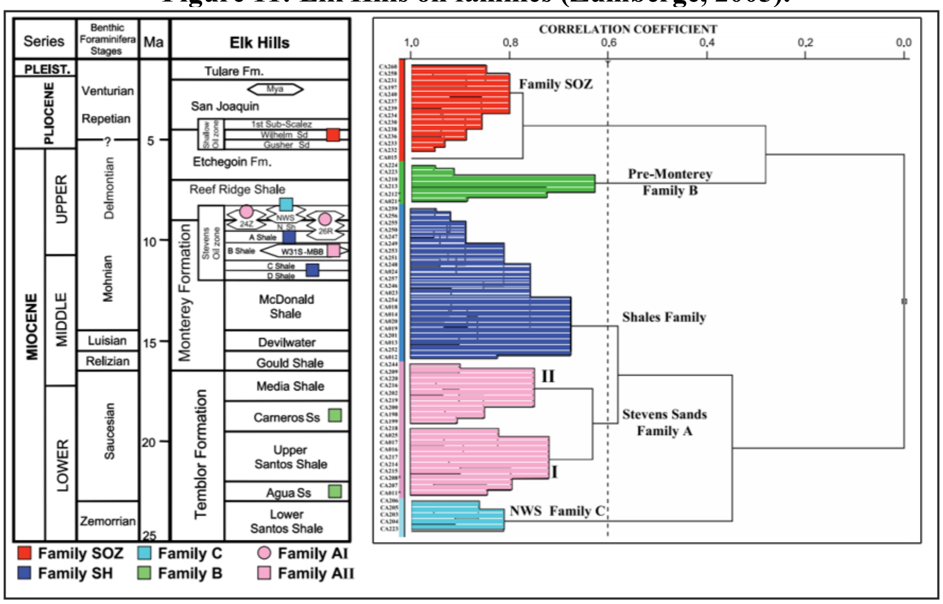
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control

Board. To date, more than 114 million barrels of water and 841 billion cubic feet of gas have been injected into the 26R Monterey Formation sands. There has been no evidence of water or gas migrating through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically confined.

3. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 11) sourced from the Miocene Monterey Formation (locations for samples are shown in Figure 2) and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests “minimal up-section, [and] cross stratigraphic migration”. The authors conclude that the hydrocarbons present in the overlying formations are from “another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs” and not the result of upward movement from the older Miocene reservoirs.

Figure 11: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

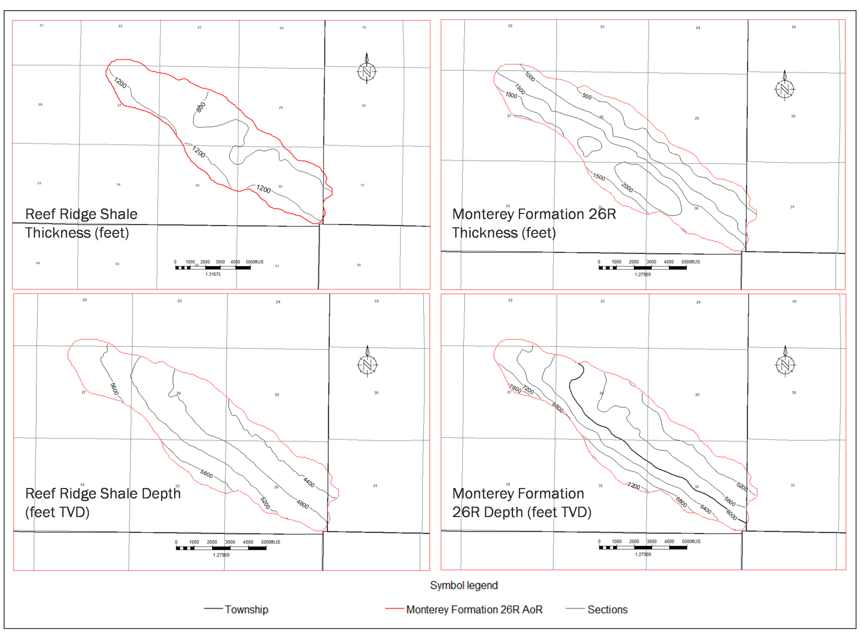
Depths and thickness of the 26R Monterey Formation reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 12) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability is due to deposition of the Monterey Formation sands.
3. Monterey Formation thickness variability is from pinch-out of the reservoir on the 31S structure.

Table 1: Reef Ridge Shale and Monterey Formation 26R thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone	Thickness (feet)	640	1,598	985.1
Reef Ridge Shale	Depth (feet TVD)	4,084	5,949	4,992
Reservoir	Thickness (feet)	255	2,497	1,283
Monterey Formation 26R Reservoir	Depth (feet TVD)	4,828	7,827	6,014

Figure 12: Reef Ridge Shale and Monterey Formation 26R thickness and depth maps.

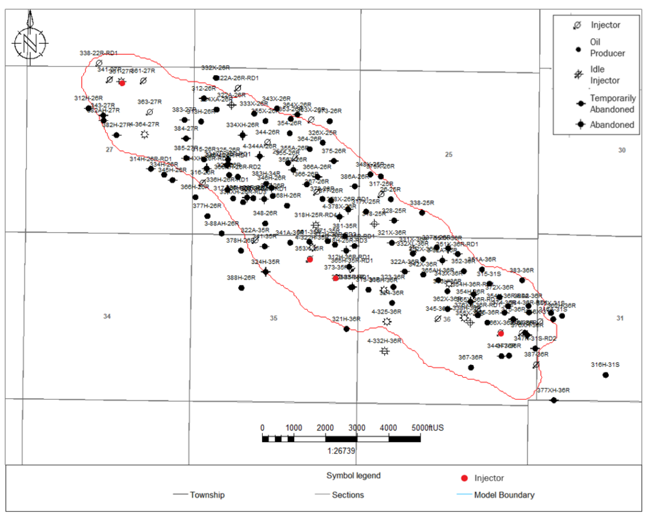


Variability in the thickness and depth of the either the Reef Ridge Shale or the 26R Monterey Formation sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

Facies Changes in the Injection or Confining Zone

The Monterey Formation 26R reservoir and Reef Ridge Shale has been defined with extensive data (Figure 13), with a total of 152 wells and spacing of 400-800 feet. Each of these wells is used to define stratigraphy, lithology/facies and reservoir properties for the static geological model and the maps shown in Figure 12. This quantity and spacing of data is more than sufficient to generate a data driven static model that define facies changes in for the reservoir and confining zone. Based on Monterey Formation 26R operational experience and plume modeling results, there are no facies changes that will either impact injection operations or confinement. During operations at the field, there were no reservoir heterogeneities that would affect injection or facilitate preferential flow. This is supported by Figure 5 that illustrates the continuity of the 26R reservoir.

Figure 13: Well data used to define the Monterey Formation 26R reservoir and confining zone. These wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) that are properties in the static geological model.



Mineralogy

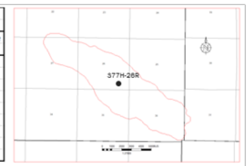
Monterey Formation 26R:

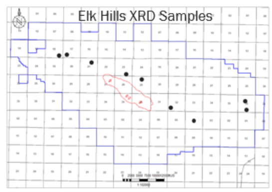
X-ray diffraction (XRD) data has been compiled and compared from 9 wells with a total of 108 data points (Figure 14). XRD samples just north of the 26R AoR are considered consistent with the reservoir because Monterey Formation sands within the Elk Hills Oil Field have similar sediment sources. Clay speciation has been found to be consistent throughout the Elk Hills Field. Well 377H-26R (Figure 14) provides an example of the mineralogy for the reservoir interval in

373-35R. Clean reservoir sand intervals have an average of 39% quartz, 49% potassium feldspar, albite and oligoclase as well as 12% total clay.

Figure 134: Monterey Formation 26R sand mineralogy from well 377H-26R and XRD sample locations in the Elk Hills Oil Field.

	Whole Rock Mineralogy (Weight %)							Relative Clay Abundance (Normalized to 100%)			
Depth	Quartz	K-Feldspar	Plagioclase	Siderite	Pyrite	Gypsum	Total Clay	Illite / Smectite *	Fe-Illite & Mica	Kaolinite	Chlorite
5912.5	38	15	32	0	1	1	13	28	65	4	3
5981.5	40	16	32	0	1	1	10	29	56	11	4
6046.0	40	14	29	0	2	0	15	32	45	20	3
6046.9	37	17	37	0	1	Tr	8	36	45	15	4
6066.4	41	18	32	0	1	0	8	30	41	26	3
6097.1	41	16	34	0	0	0	9	19	53	25	3
6113.3	35	19	34	0	1	0	11	16	46	33	5
6141.0	44	6	17	3	3	1	26	75	22	3	0





Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 15). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

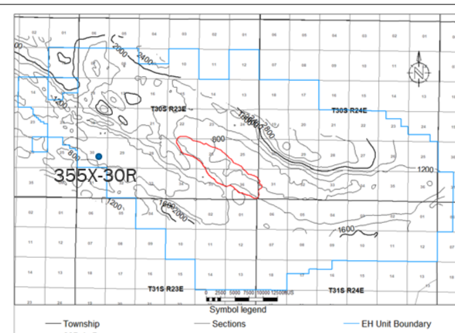
This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AoR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 14: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.

FTIR Mineralogy

(Weight Percent)

Depth (ft)	Density (g/cc)	Quartz	Albite	Oligoclase	Andesine	K-Feldspar	Calcite	Dolomite	Pyrite	Opal-A	Opal-CT	Chert	Cristobalite	Total Clay	Kaolinite	Chlorite	Illite+Smectite
5285.5	2.51	12	9	0	10	10	0	0	0	0	26	0	0	33	5	3	25
5290.0	2.38	0	5	0	0	6	2	0	2	0	57	0	19	9	5	0	4
5291.8	2.51	0	7	0	3	9	3	0	3	0	39	11	0	25	9	0	16
5295.5	2.49	0	7	0	0	8	3	0	2	0	42	12	0	26	8	0	18
5299.2	2.52	0	0	0	0	5	0	35	1	0	35	0	19	5	4	0	1
5299.8	2.49	0	7	0	3	7	0	0	2	0	37	13	0	31	9	0	22
5302.2	2.44	0	8	0	0	7	0	0	2	0	39	7	13	24	9	0	15
5304.2	2.50	0	6	0	3	8	1	2	2	0	25	9	10	34	9	0	25
5308.1	2.51	0	7	0	6	5	0	3	0	0	23	17	0	39	11	0	28
5318.0	2.50	0	7	0	3	7	2	0	2	0	34	14	0	31	8	0	23
5325.0	2.52	12	0	0	9	7	0	3	0	0	23	0	0	46	14	0	32
5333.0	2.51	10	7	0	3	6	0	2	1	0	30	0	0	41	12	0	29
5336.9	2.37	0	5	0	0	4	0	0	2	0	63	0	20	6	4	0	2
5338.8	2.48	0	8	0	0	9	2	0	3	0	45	10	0	23	8	0	15
5341.2	2.81	0	0	0	0	3	3	75	1	0	0	12	0	6	0	0	6
5341.7	2.50	9	6	0	4	8	0	0	2	0	34	0	0	37	12	0	25
5346.1	2.78	0	0	0	0	0	4	70	0	0	0	18	0	8	0	0	8
5350.1	2.49	13	5	11	0	3	0	2	0	0	31	0	0	35	12	0	23
5356.0	2.51	16	7	0	5	8	0	2	0	0	25	0	0	37	11	0	26
5361.1	2.82	0	0	0	0	0	2	81	1	0	0	10	0	6	0	0	6
5364.6	2.37	0	0	0	0	9	0	0	1	0	58	0	22	10	5	0	5
5371.0	2.55	0	7	0	2	10	2	0	3	0	25	16	0	35	9	0	26
5380.6	2.37	0	7	0	0	4	1	0	0	0	58	0	16	14	5	0	9
5381.0	2.49	10	5	12	8	8	0	0	0	0	29	0	0	28	4	0	24
5383.3	2.41	0	6	0	0	8	1	1	1	0	47	0	17	19	7	0	12
5386.4	2.39	0	7	0	0	7	1	0	1	0	52	0	17	15	6	0	9
5387.4	2.45	0	7	0	2	7	2	2	0	0	32	7	15	26	8	0	18
5391.4	2.40	0	8	0	0	6	0	0	1	0	51	5	16	13	6	0	7
5398.6	2.51	11	6	0	5	6	2	2	0	0	28	0	0	40	14	0	26
5406.5	2.49	0	6	0	2	7	5	0	0	0	31	13	0	36	11	0	25
5410.9	2.41	0	7	0	0	8	2	0	1	0	46	0	16	20	7	0	13
5416.2	2.45	0	8	0	0	7	0	0	0	0	44	10	0	31	9	0	22
5418.5	2.46	5	6	0	2	8	2	0	0	0	30	0	11	36	11	0	25
5423.6	2.51	0	7	0	0	8	3	0	2	0	33	15	0	32	7	0	25
5433.5	2.51	12	6	0	7	8	0	0	0	0	26	0	0	41	12	0	29
5447.5	2.46	0	8	0	0	6	0	0	1	0	45	13	0	27	8	0	19



335X-30R Reef Ridge Shale confining layer core analysis.

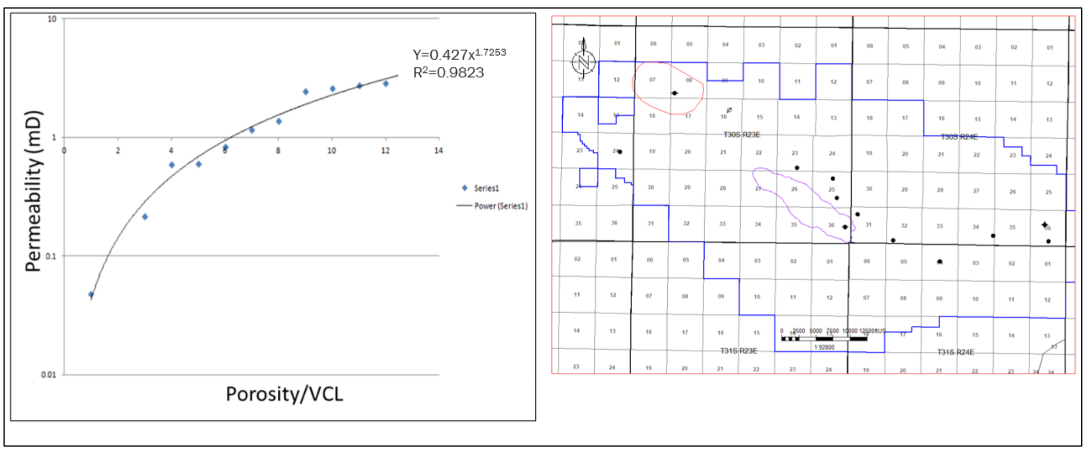
Porosity and Permeability

26R Monterey Formation:

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

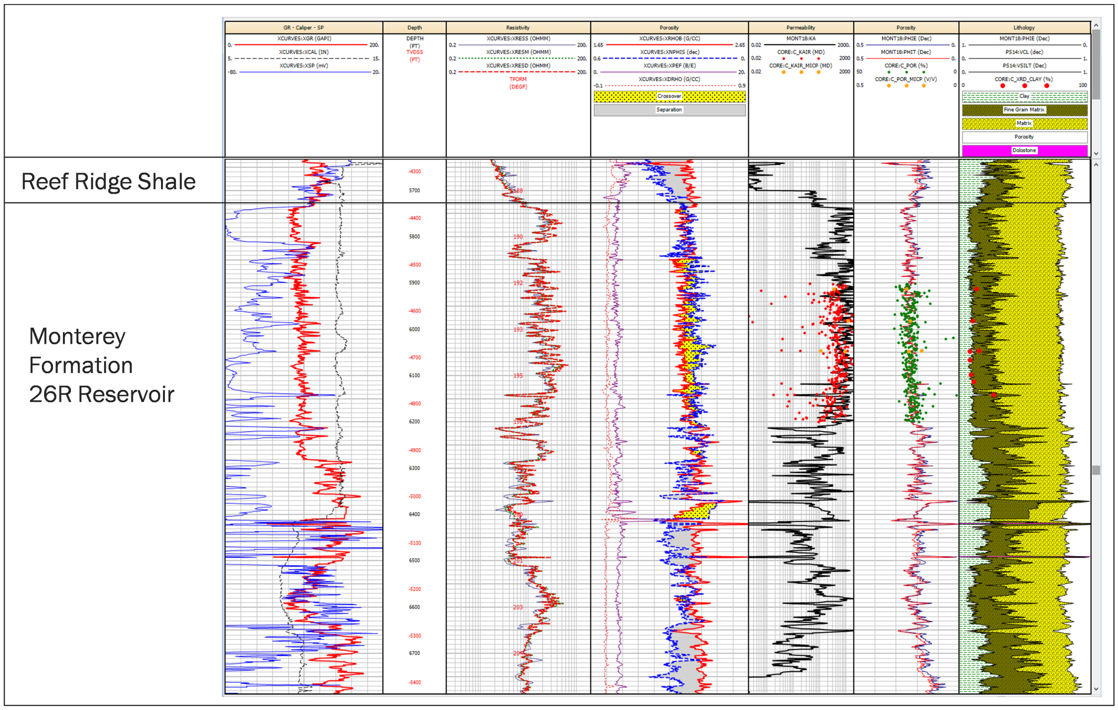
> Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.
>
> Volume of clay is determined by neutron-density separation and is calibrated to core data.
>
> Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 16 below.

Figure 15: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume.



In the example below for the 26R Monterey Formation sands, the porosity ranges from 20% - 30% with a mean of 24%. The permeability ranges from 3 mD – 1,500 mD with a log mean of 45 mD (Figure 17).

Figure 16: Porosity and permeability for well 377H-26R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2). For each of the project wells, Table 3 shows the average porosity and permeability of the Reef Ridge Shale.

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006

TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

Table 3: Reef Ridge porosity and permeability for project wells.

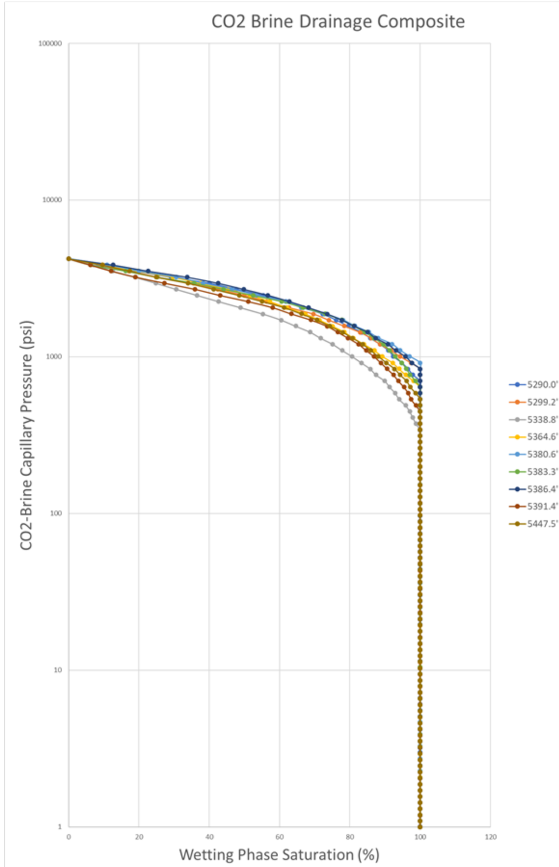
Well	Permeability (mD)	Porosity (%)
376-36R	0.0043	16
353X-35R	0.0005	12
328-25R	0.0174	20
345-36R	0.0012	15
341-27R	0.0002	11
363-27R	0.0002	10
373-35R	0.0001	10

Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 18). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 17: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR and area, 11 wells (Figure 19) had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 22,592 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

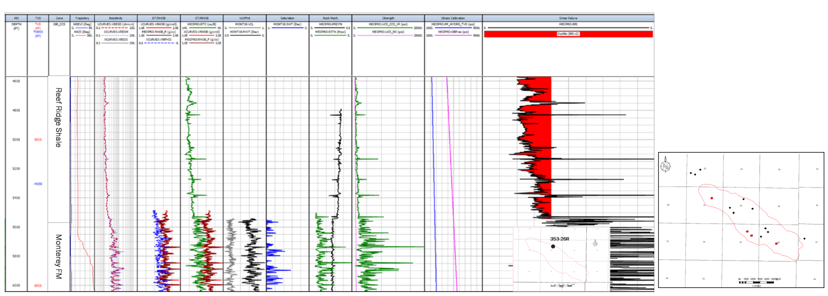
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 353-26R is shown below (Figure 19). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method.

Figure 18: Unconfined compressive strength and ductility calculations for well 353-26R. The Reef Ridge Shale ductility is shaded where less than two.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than two, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. The BRI less than two confirms that the Reef Ridge is a ductile confining layer.

The average ductility of the confining zone based on data from 11 wells is 1.59.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,385 PSI.

As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the 26R Monterey Formation reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 20 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

Figure 20: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).

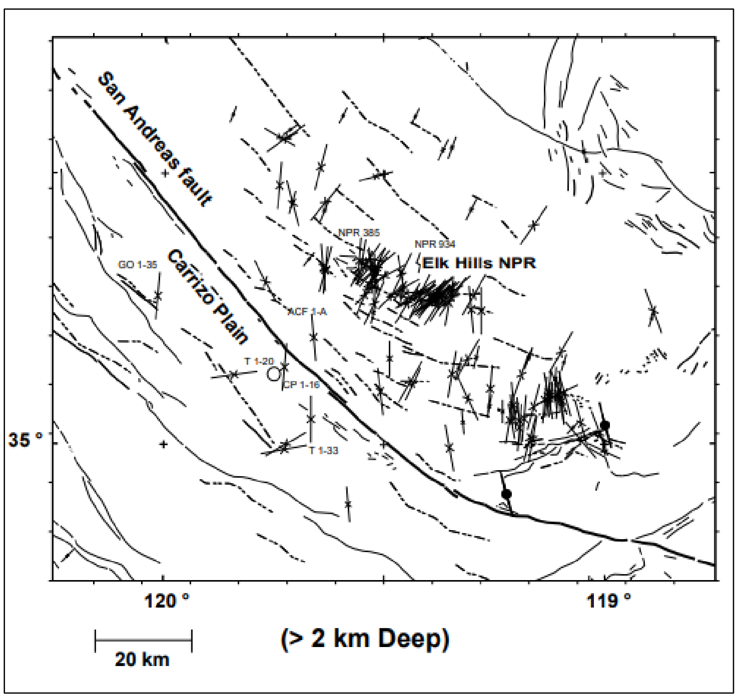


Table 4 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation 26R reservoir.

Table 4: Pressure gradients for the Monterey Formation 26R reservoir and Reef Ridge Shale. The Reef Ridge Shale fracture gradient and pressure will be determined during pre-operational testing. The Monterey Formation fracture gradient is based on a test in well 388-26R. The overburden gradient was determined by integrating density logs.

Stress	Reef Ridge Confining Layer	Monterey Formation
Pore Pressure Gradient (psi/ft)	0.433	0.5
Overburden Gradient (psi/ft)	0.91	0.92
Fracture Gradient (psi/ft)	TBD	0.701

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 5. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 5: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, PSI**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

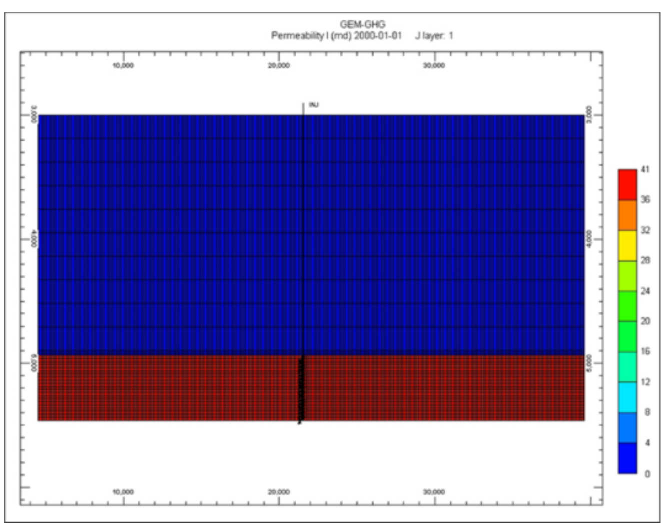
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 21.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 21: Geomechanics Model.

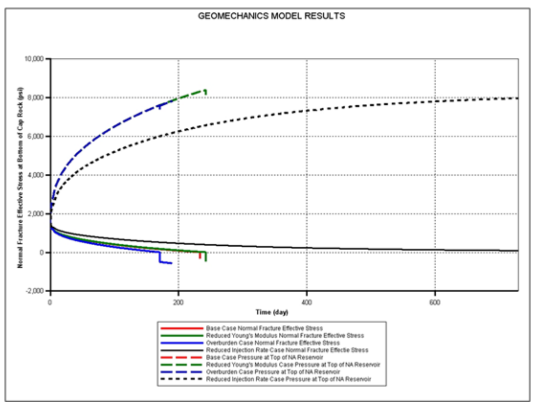


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 22 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 19: Normal Fracture Stress and Pressure for Geomechanics Cases. Base case follows the reduced Young's Modulus case.



Geomechanical Modeling Parameters

The geomechanical parameters used in the modeling were selected to represent a range of values for thickness, poisons ratio and Youngs Modulus. The following is a short description for parameter variability selection:

> **Thickness:** Reef Ridge thickness scenarios for the geomechanical modeling was 795 feet and 1,935 feet. The mean thickness of the Reef Ridge Shale confining layer overlying the Monterey Formation 26R AoR is 985 feet thick (Figure 12) as derived from open-hole log interpretation, which is between the parameters modeled.

Poisson's Ratio: Compressional and shear sonic logs were used to calculate Poisson's Ratio (Yale, 2017).

$$\nu_{dyn} = \nu_{stat} = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)}$$

The following table shows the range of values determined for Poisons Ratio and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case	10	50	90
Confining Layer Reef Ridge	0.23	0.23	0.23	0.29	0.33	0.36
Reservoir 26R	0.25			0.19	0.27	0.35

Young's Modulus: Young's Modulus was calculated using compressional and shear sonic and bulk density logs. The dynamic to static correction applied was the Lacy shale method (Lacy, 1997):

$$E_{dyn} = \frac{\rho V_s^2 (3V_p^2 - 4V_s^2)}{(V_p^2 - V_s^2)}$$

- See equation 8.1 in Fjaer et. al, 2008

$$E_{stat} = 0.0428E_{dyn}^2 + 0.2334E_{dyn}$$

- See equation 2 in Lacy, 1997.

The following table shows the range of values determined for Young's Modulus and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case	10	50	90
Confining Layer Reef Ridge	0.9	0.8	0.6	0.6	0.71	0.87
Reservoir 26R	0.725			0.79	0.90	1.07

Seismic History [40 CFR 146.82(a)(3)(v)]

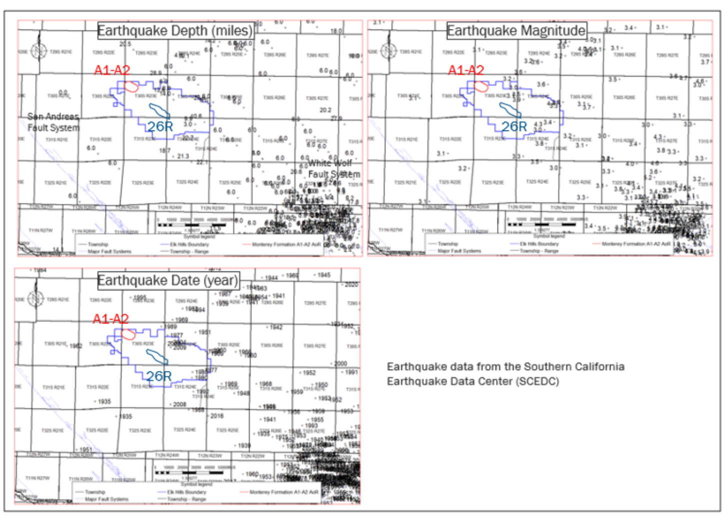
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

There have been no earthquakes in the AoR (Figure 23). In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 23: Earthquakes in the southern San Joaquin Basin with a magnitude greater than 3 since 1932.



Seismic Risk:

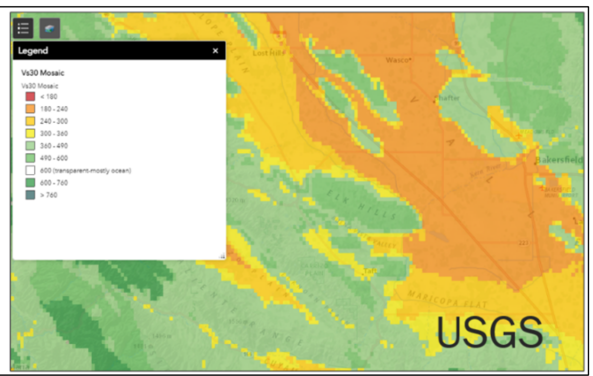
The EHOF has been closely monitored for the effects of seismicity by CTV and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30 means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

Figure 24: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.

Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

Site Class	S-Velocity (Vs) (ft/sec)	S-Velocity (Vs) (m/sec)
A (Hard Rock)	> 5,000	> 1500
B (Rock)	2,500 – 5000	760 – 1500
C (Very Dense Soil and Soft Rock)	1,200 – 2,500	360 – 760
D (Stiff Soil)	600 – 1,200	180 – 360
E (Soft Clay Soil)	< 600	< 180
F (Soils requiring additional response)	< 600, and meeting some additional conditions.	< 180, and meeting some additional conditions.



Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

The following is a summary of CTVs seismic risk:

Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO2 proposed to be injected.

- Extensive historical operations in the Monterey Formation 26R reservoir is valuable experience to understand operating conditions such as injection volumes and reservoir containment. The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
- VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
- There are no faults or fractures identified in the AoR that will impact the confinement of CO2 injectate.

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;

- The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur.
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations.

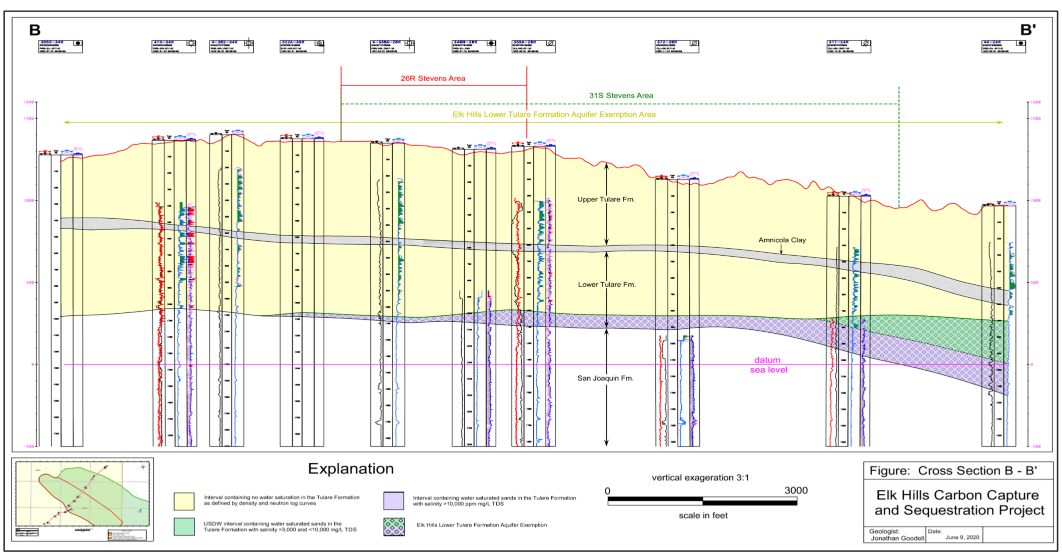
Poses a low risk of inducing a felt seismic event.

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining layer.
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.
- The operational strategy of keeping the reservoir pressure at or beneath the initial pressure of the reservoir has been designed to reduce the risk for seismic events.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

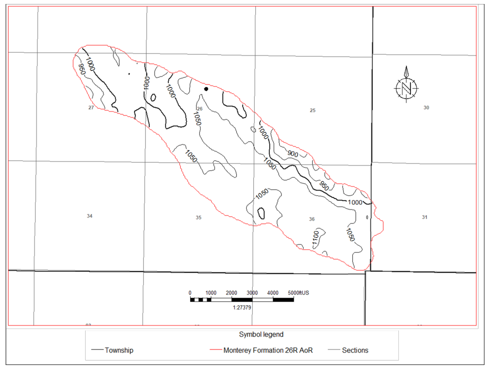
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 25). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 25: The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands are unsaturated in the 26R area.



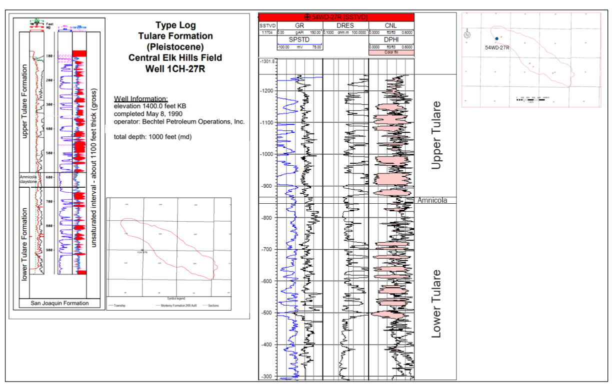
The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 25). The depth is 900 - 1,000 feet and the thickness ranges from 900 – 1,000 feet (Figure 26). The average depth of the Upper Tulare in the AoR is 502 feet TVD. The separation between the Upper Tulare and the Reef Ridge is 4,490 and the injection zone is 5,512 feet.

Figure 26: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 27). The characteristic density-neutron crossover (red-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 27: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, and Lower Tulare exempt aquifer.



Tulare Formation (Figure 28) water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum contaminant levels (MCL).

In 2018 the Lower Tulare aquifer was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

Figure 28: Upper Tulare and Lower Tulare Formation water analysis.

Upper Tulare

Table 4a. WATER SOURCE WELL #43WS-13S
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1280	1300	1200	1300
Potassium, K	9.2	9.6	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4480	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4980	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	150	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohm	1.43 ohm	1.43 ohm	1.43 ohm
NOTE: Sample analysis is from Zalco Laboratory.				

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411064-01 | Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.23	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

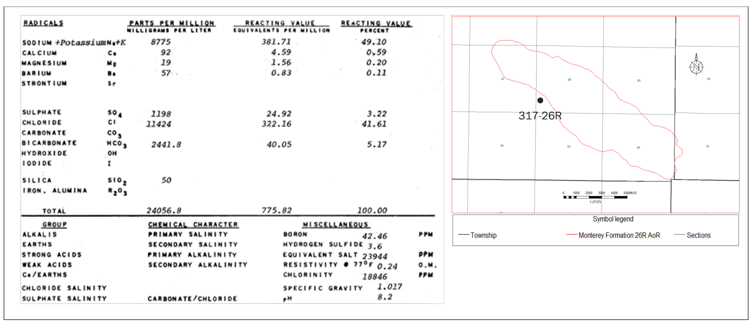
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry 26R Reservoir:

The 26R Monterey Formation reservoir has a gas cap that overlies a thin oil band and a basal water zone. CTV and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Geochemical water analysis for the 26R Monterey Formation reservoir has been completed across the AoR and collected since reservoir discovery as part of routine surveillance. This data is consistent through time and over the AoR, Figure 29 shows the geochemical water analysis for well 317-26R.

Figure 29: Monterey Formation 26R reservoir water geochemistry from well 317-26R.

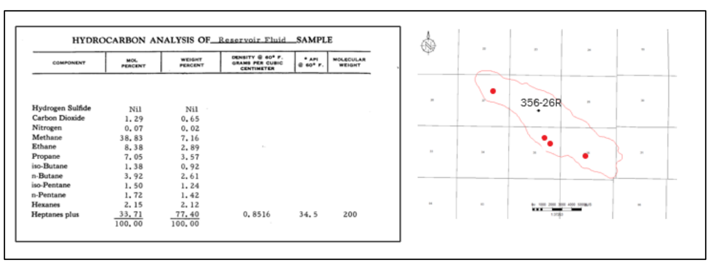


RADICALS		PARTS PER MILLION MILLIGRAMS PER LITER	REACTING VALUE EQUIVALENTS PER MILLION	REACTING VALUE PERCENT
SODIUM +Potassium	Na+K	8775	381.71	49.10
CALCIUM	Ca	92	4.59	0.59
MAGNESIUM	Mg	19	1.56	0.20
BARIUM	Ba	57	0.83	0.11
STRONTIUM	Sr			
SULPHATE	SO_4	1198	24.92	3.22
CHLORIDE	Cl	11424	322.16	41.61
CARBONATE	CO_3			
BICARBONATE	HCO_3	2441.8	40.05	5.17
HYDROXIDE	OH			
IODIDE	I			
SILICA	SIO_2	50		
IRON, ALUMINA	R_2O_3			
TOTAL		24056.8	775.82	100.00

GROUP	CHEMICAL CHARACTER	MISCELLANEOUS		
ALKALIS	PRIMARY SALINITY	BORON	42.46	PPM
EARTHS	SECONDARY SALINITY	HYDROGEN SULFIDE	3.6	
STRONG ACIDS	PRIMARY ALKALINITY	EQUIVALENT SALT	23944	PPM
WEAK ACIDS	SECONDARY ALKALINITY	RESISTIVITY @ 77°F	0.24	O.M.
Ca/EARTHS		CHLORINITY	18846	PPM
CHLORIDE SALINITY		SPECIFIC GRAVITY	1.017	
SULPHATE SALINITY	CARBONATE/CHLORIDE	pH	8.2	

The hydrocarbon composition for the Monterey Formation 26R reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 30 shows the results of the hydrocarbon composition for well 356-26R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 30: Monterey Formation reservoir hydrocarbon analysis from well 356-26R.



HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PERCENT	WEIGHT PERCENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	1.29	0.65			
Nitrogen	0.07	0.02			
Methane	38.83	7.16			
Ethane	8.38	2.89			
Propane	7.05	3.57			
iso-Butane	1.38	0.92			
n-Butane	3.92	2.61			
iso-Pentane	1.50	1.24			
n-Pentane	1.72	1.42			
Hexanes	2.15	2.12			
Heptanes plus	33.71	77.40	0.8516	34.5	200
	100.00	100.00			

26R Monterey Formation Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The 26R Monterey Formation reservoir will store 7% of the injectate CO_2 in aqueous phase with water saturations of 34% saturation in the gas cap, 25% in the oil band and 100% in the basal water.
2. Residual oil saturation (15- 37%) in the 26R Monterey Formation reservoir will dissolve 20% of the CO_2 injectate.
3. The Monterey Formation has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will stay on grain surfaces.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and is discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Geochemical Modeling of 26R Monterey Formation and Reef Ridge Shale:

Geochemical modeling has been carried out to understand the potential interactions of the injectate with the formation mineralogy and fluids. The modeling was carried out for the 26R Monterey formation injection zone and for the Reef Ridge shale confining zone, using the USGS geochemical modeling software PHREEQC (ph-REdox-Equilibrium).

The model was set up using the formation fluid data referenced in the "Geochemistry 26R Reservoir" section and using mineralogy data referenced in the "Mineralogy" section of this document. The injectate compositions used for the modeling are detailed in the "Appendix: 26R Geochemical modeling" and in the "Proposed Carbon Dioxide Stream" section of the Attachment B document.

The Geochemical modeling indicates, as expected, that due to the dominant stable quartz and feldspar mineralogy of the formation, only minimal amounts of minerals will dissolve and precipitate. The net modeled change in molar mass was -0.2% to 1.2% for the Monterey 26R formation and about 1% in the Reef Ridge shale confining zone. As such the Injection zone, Confining zone and Formation fluids can be considered compatible with the proposed injectates, with the geochemical modeling indicating no significant reactions that might affect injection and storage at the site.

Details of the modeling methodology and results can be found in "Appendix: 26R Geochemical modeling".

CTV will review and confirm the geochemical modeling as part of pre-operational testing based on injectate sampling to ensure that they are consistent with the model inputs.

Geochemistry Etchegoin Reservoir:

The Etchegoin Formation reservoir geochemistry is shown in Figure 31. The total dissolved solids of the water is 31,725.4 from well 24H-26R, demonstrating that the reservoir is not of USDW water quality.

Figure 31: Etchegoin Formation water geochemistry from well 24H-26R in the AoR.

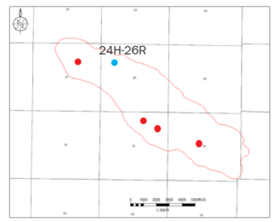
Well Name:	24H-26R
Sample Point:	Wellhead
Sample Date:	2/4/2014
Sample ID:	WA-265899

Scaling potential predicted using ScaleSoftPitzer from Brine Chemistry Consortium (Rice University)

Sample Specifics	
Test Date:	2/14/2014
System Temperature 1 (°F):	200
System Pressure 1 (psig):	2000
System Temperature 2 (°F):	60
System Pressure 2 (psig):	15
Calculated Density (g/ml):	1.019
pH:	6.50
Calculated TDS (mg/L):	31725.40
CO_2 in Gas (%):	
Dissolved CO_2 (mg/L)):	360.00
H_2S in Gas (%):	
H_2S in Water (mg/L):	2.50

Notes:
80F / 200psi
Conductivity at 70F - 0.0496 S/cm

Analysis @ Properties in Sample Specifics			
Cations	*mg/L*	*Anions*	*mg/L*
Sodium (Na):	11623.80	Chloride (Cl):	19000.00
Potassium (K):	0.10	Sulfate (SO_4):	0.00
Magnesium (Mg):	122.00	Bicarbonate (HCO_3):	414.80
Calcium (Ca):	520.00	Carbonate (CO_3):	
Strontium (Sr):	0.00	Acetic Acid (CH_3COO)	
Barium (Ba):	22.60	Propionic Acid (C_2H_5COO)	
Iron (Fe):	21.30	Butanoic Acid (C_3H_7COO)	
Zinc (Zn):	0.00	Isobutyric Acid ($(CH_3)_2CHCOO$)	
Lead (Pb):	0.00	Fluoride (F):	
Ammonia NH_3:		Bromine (Br):	
Manganese (Mn):	0.79	Silica (SiO_2):	



Site Suitability [40 CFR 146.83]

The 26R Monterey Formation reservoir in the 31S anticline was discovered in the 1940's and developed in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the 26R Monterey Formation reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

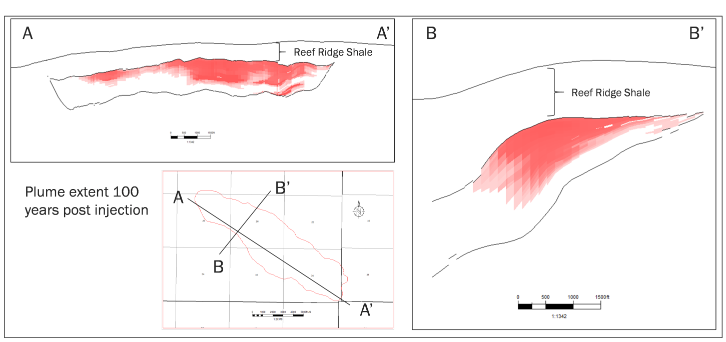
A key component of the 26R Monterey Formation reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale).

CO_2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Monterey Formation 26R reservoir hydrocarbons were confined for several million years.
2. The Reef Ridge Shale primary confining layer is 800-1,000 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 841 billion cubic feet of gas and 114 million barrels of water with no leakage.
3. Cross section A-A' (Figure 32) shows confinement of the injected CO_2 plume by up-dip pinch-out of the reservoir on the anticline structure and lateral confinement by reservoir edges. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does not migrate beyond the edges of the anticline structure or into the Reef Ridge Shale.

Figure 32: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the Monterey Formation 26R sand facies and the edges of the reservoir.



Storage capacity for the Monterey Formation 26R storage reservoir based on computational modeling results is up to 38 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate volume.

References:

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4. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.